RESPONSIVENESS SUMMARY
ALLEGHENY ENERGY SUPPLY
AIR QUALITY CONTROL PERMIT NUMBER 1001743

OPENING NOTE

A list of abbreviations used within this document can be found at the end of this document.

INTRODUCTION

Allegheny Energy Supply (Allegheny) applied for a Class I Prevention of Significant Deterioration (PSD) air quality control permit, number 1001743, for the operation of an electric utility power plant (the La Paz Generating Facility) to be located approximately 75 miles west of Phoenix, along Interstate Highway 10, in La Paz County, Arizona.

The La Paz Generating Facility is a natural gas-fired, combined cycle merchant power plant that will have the option of using either Siemens-Westinghouse (SW) 501F combustion turbine generators (CTG) or General Electric (GE) 7FA CTGs. The facility will have a total rating of either 1,080 Megawatts (MW) (nominal) with the SW501F turbines, or 1,040 MW with the GE7FA turbines. It will consist of two power blocks rated at 540 MW each using the SW501F, or 520 MW each using the GE7FA turbines.

The project is classified as Standard Industrial Classification Code 4911 and North American Industrial Classification System 221112, Fossil-Fuel Electric Power Generation. The primary processes at this facility consist of the following equipment:

A single power block for the SW501F configuration is made up of the following equipment:

- Two (2) SW CTGs equipped with dry low-nitrogen oxide (low-NO_x) combustors;
- Two (2) Heat Recovery Steam Generators (HRSGs) with supplemental duct firing at a rated heat capacity of 255.1 million British Thermal Units per hour (MMBtu/hr) (higher heating value (HHV));
- One (1) Steam Turbine Generator (STG) unit
- Two (2) selective catalytic reduction (SCR) systems for controlling nitrogen oxide (NO_x) associated with the CTG/HRSGs; and
- Two (2) oxidation catalyst systems for controlling carbon monoxide and volatile organic compounds (VOCs) - associated with the CTG/HRSGs.

The support processes associated with the SW501F configuration will consist of the following equipment:

- Two (2) 10-cell (5 by 2) wet mechanical-draft cooling towers equipped with high efficiency drift eliminators for the steam turbine condenser and equipment cooling;
- One auxiliary boiler with a maximum natural gas fuel burn rate of 55.34 MMBtu/hr and equipped with low-NOx burners;
- Two (2) diesel-fueled emergency generators each rated at 1,115 horsepower (hp);
- Two (2) diesel-fueled engines that drive the emergency fire water pumps rated at 250 hp;
- Main transformers; and
- Other ancillary equipment.

A single power block for the GE7FA configuration is made up of the following equipment:

- Two (2) GE7FA CTGs equipped with dry low-NO_x combustors;
- Two (2) HRSGs with supplemental duct firing at a rated heat capacity of 640 MMBtu/hr (HHV);
- One (1) STG unit;
- Two (2) SCR systems for controlling NO_x associated with the CTG/HRSGs; and
- Two (2) oxidation catalyst systems for controlling CO and VOCs associated with the CTG/HRSGs.

The support processes associated with the GE7FA configuration will consist of the following equipment:

- Two (2) 10-cell (5 by 2) wet mechanical-draft cooling towers equipped with high efficiency drift eliminators for the steam turbine condenser and equipment cooling;
- One auxiliary boiler with a maximum natural gas fuel burn rate of 41.0 MMBtu/hr and equipped with low-NOx burners;
- One (1) diesel-fueled emergency generator rated at 1,115 hp;
- Two (2) diesel-fueled engines to drive the emergency fire water pump each rated at 250 hp;
- Main transformers; and
- Other ancillary equipment.

Pollution control measures and equipment required by this permit include low-nitrogen oxide burners and SCR on the combined cycle systems to control NO_x; an oxidation catalyst on the combined cycle systems for reducing CO and VOCs; and high-efficiency drift eliminators on the wet cooling towers for reducing particulate matter emissions.

PROCESS DESCRIPTION

The combustion turbine compresses chilled air which is mixed with natural gas and burned in the dry low-NO_x combustors. The resulting high temperature gases pass through the power turbine and exhaust to the HRSGs. The power turbine drives both the compressor and an electrical generator. The generators on each CTG are capable of producing 180 MW (International Standards

Organization (ISO) conditions). The turbine exhaust gases are treated with an SCR system and an oxidation catalyst to further control NO_x, CO, and VOC emissions before being exhausted to the atmosphere.

The HRSGs are boilers that generate steam from the heat in the CTG exhaust gases. To increase overall output from the facility, supplemental (duct) firing of the HRSGs using natural gas may be performed so that additional steam can be produced for the STG. As a result, the HRSGs will generate additional emissions due to the firing of the duct burners. The STGs are capable of generating 180 MW each. Because the STGs do not combust fuel, there are no air emissions from these units.

Low pressure, low temperature steam exhausted from the STG is condensed in the main condenser. The condensate is recycled for use in generating more steam. The condenser is cooled by the circulating water system that rejects waste heat to the atmosphere by evaporation in the cooling towers. Particulate matter that is entrained in the water vapor escaping from the cooling towers is controlled by high efficiency drift eliminators.

Pollution control equipment for the La Paz Generating Facility include an SCR system and an oxidation catalyst to control NO_x, CO, and VOC emissions from the exhaust gases that exit the CTGs and the HRSGs, before they are vented to the atmosphere. The STGs do not combust fuel, so there are no air emissions from these units. High-efficiency drift eliminators are also used to control PM emissions from the wet cooling towers.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Allegheny was required to submit a demonstration that all pollutants emitted in significant amounts would comply with BACT. The Department conducted a thorough review of the information provided by Allegheny and supplemented this information through independent research. The information that the Department considered included manufacturer's data, data obtained from Environmental Protection Agency's (EPA) RACT/BACT/LAER Clearinghouse (RBLC) (http://cfpub1.epa.gov/rblc/htm/bl02.cfm), and reports on current environmental developments. On several occasions, the Department required Allegheny to submit additional analyses, either to correct deficiencies or to take into account recent developments in the industry.

Combined Cycle Systems

The combined cycle systems include the CTGs and supplemental duct firing of the HRSGs. The duct burners and CTGs have a common release point, and the duct burners will never operate when the turbines are not operating. For these reasons, the BACT analyses are conducted for the combined emission rates of the CTGs and duct burners. For each pollutant, the Department considered all available control technologies and considered application of these technologies on the combined emissions from the CTGs and duct burners when setting emission limits.

> Particulate Matter less than 10 Microns in Diameter (PM_{10}). The amount of both filterable PM_{10} and condensible PM_{10} emissions from natural gas-fired CTGs should be very small relative to the total exhaust flow. There are no known applications of add-on controls for the purpose of controlling PM_{10} from natural gas-fired units, because the combustion of this fuel

does not form much PM or PM_{10}. Allegheny has demonstrated that the use of good combustion practices and natural gas in association with emission limits of 30.3 pounds per hour (lb/hr) if using SW501F CTGs, and 45.5 lb/hr if using GE7FA CTGs, represents *BACT* for PM_{10}. Both limits apply with and without duct firing.

Nitrogen Oxides (NO_x). Emissions from the exhaust of the combined cycle systems will be minimized by:

- Use of SCR on each combined cycle system;

- Dry low-NO_x combustors in the turbines and low-NO_x burners in the HRSG; and

- Use of natural gas, which has a low fuel-bound nitrogen content.

The NO_x emission limit is initially proposed at 2.5 parts per million by volume on a dry basis (ppmvd) on a 1-hour (hr) average with a demonstration period that may reduce the emission limit to 2.0 ppmvd on a 1-hr average. The demonstration period consists of the first two years of operation. During this time the source is required to properly install, operate, and maintain the *SCR* system in order to evaluate its performance in meeting the lower emission limit. The Arizona Department of Environmental Quality (ADEQ) is allowing the two-year demonstration period given that a 2.0 ppmvd NO_x BACT limit has only recently been demonstrated in practice. To help demonstrate the appropriate installation, operation, and maintenance of the SCR system to meet the demonstration limit, Allegheny is required to submit design specifications of the SCR system, an SCR operating plan, and semi-annual performance reports to the Director.

In addition to the proposed controls, the Department evaluated other process controls and add-on controls for the combined cycle systems. One type of control measure is in-combustor controls such as water and steam injection. These controls have been superseded by dry low-NO_x combustors, due to the superior emission control performance, increased efficiency, and control without the need for large volumes of purified water.

Selective Non-Catalytic Reduction (SNCR), $SCONO_x$, and XONON were also considered as post-combustion NO_x control systems. Among post-combustion control systems, the XONON catalytic system was rejected because it is not technically feasible. XONON is an emerging technology and is not commercially available at this time for CTGs of the size proposed for this project. SNCR was also rejected as a possible control system because the technology requires gas temperatures in the range of 1200 to 2000 degrees Fahrenheit (°F), and the exhaust temperature for the proposed turbines, i.e. 600°F, is below the minimum SNCR operating temperature. $SCONO_x$ was rejected as not being cost-effective when compared to SCR.

Carbon Monoxide (CO). CO is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_x

during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer combustor designs and control systems limits the impact of fuel staging on CO emissions.

The applicant considered catalytic oxidation and good combustion controls as possible control technologies. As noted previously, $SCONO_x$ can control both NO_x and CO, and the additional control of CO was incorporated into the cost analysis. $SCONO_x$ was rejected for economic considerations and is not considered further. An oxidation catalyst represents the most stringent control option. Thus, no further analysis of control technologies is required.

The applicant is proposing the use of an oxidation catalyst, in addition to combustion controls, to reduce CO to 3 ppmvd at 15% O_2 with and without duct firing, on a 3-hour average. Upon review of the data, ADEQ concurs with and approves the applicant's BACT proposal.

Volatile Organic Compounds (VOC). The proposed combustion turbines and duct burners are natural gas-fired combustion units. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion, and recombination of the products of incomplete combustion. Complete combustion is a function of three key variables: time, temperature, and turbulence. Once the combustion process begins, there must be enough time at the required combustion temperature to complete the process, and during combustion there must also be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air.

Combustion systems with poor control of the fuel to air ratio, poor mixing, or insufficient time at combustion temperatures have higher VOC emissions than those with good controls. The proposed turbines and duct burners incorporate state-of-the-art combustion technology, and both are designed to achieve high combustion efficiencies. As a result, the proposed combustion equipment has very low expected VOC emission rates.

The two most prevalent components of natural gas, methane (approximately 94% by volume) and ethane (approximately 4% by volume), are not defined as VOCs. The remaining portions of natural gas are propane and trace quantities of higher molecular weight hydrocarbons, all of which are nearly 100% combusted. The high energy efficiency of turbines and duct burners and low fraction of VOCs in natural gas result in a very low VOC emissions rate for the proposed new units. Additionally, the recombination of products of incomplete combustion is unlikely in well controlled turbine/duct burner systems because the conditions required for recombination are not present.

The applicant considered $SCONO_x$, catalytic oxidation, and good combustion controls as possible control technologies. As noted previously, $SCONO_x$ can control NO_x, CO, and VOC, and the additional control of VOC was incorporated into the cost analysis. $SCONO_x$ was rejected for economic considerations and was not considered further. An oxidation catalyst represents the most stringent control option. Thus, no further analysis of control technologies is required.

The applicant is proposing the use of an oxidation catalyst, in addition to combustion controls, to reduce VOC emissions to 2.5 ppmvd at 15% O_2 for the SW turbines and 4.5 ppmvd at 15% O_2 for the GE turbines, with and without duct firing, on a 3-hour average. Upon review of the data, ADEQ concurs with and approves the applicant's BACT proposal.

Sulfur Dioxide (SO_2) The proposed combustion turbines and duct burners will be designed and operated to minimize emissions and will be fired solely with natural gas, which is inherently low in sulfur. Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Add-on control devices (e.g., scrubbers) are typically used to control emissions from combustion sources firing higher sulfur fuels, such as coal. Flue gas desulfurization is not appropriate for use with low sulfur fuel, and is not considered for this project, because the realizable emission reduction is far too small for this option to be cost-effective.

There are no known applications of add-on controls for the purpose of controlling SO_2 from natural gas-fired units. Therefore, the applicant has demonstrated that the use of good combustion practices and natural gas represents BACT for SO_2. The fuel will be limited by the maximum allowable sulfur content in the natural gas of 0.75 grains/100 dry standard cubic foot (dscf) and a limit of .0021 lb/MMBtu.

Wet Cooling Towers

The La Paz Generating Facility, as proposed, will include two mechanical-draft wet cooling towers. The PM formation in wet cooling towers is due to droplets of cooling water that escape, or "drift," from the tower. These water droplets contain some quantity of suspended and dissolved solids. As the water droplet evaporates, the dissolved and suspended solids become airborne *PM*.

Particulate Matter (PM). Particulates are emitted from cooling towers when small droplets of cooling water, called drift, are emitted and evaporate. The dissolved and suspended materials in the drift can become airborne particles when the water around them evaporates. The size distribution of the emitted particulates includes particles in both the PM and PM_{10} range.

The primary factor that controls the amount of PM_{10} from the cooling tower is the droplet drift rate. A droplet drift rate of 0.0005 percent (achieved through the use of high efficiency drift eliminators on the cooling tower) was determined to represent BACT for the cooling towers. The BACT limit is based on vendor guarantees and is consistent with the most stringent limits listed in the RBLC.

ADEQ also requested the applicant consider a dry, air-cooled condenser in lieu of a wet cooling tower as the top control option in its cooling tower BACT analysis. The applicant provided cost data for such a dry system that demonstrated that the technology was not economically feasible when compared to a wet cooling tower. Consequently, the Department concludes that the high efficiency drift eliminators with an efficiency of 0.0005 percent are BACT for PM_{10} for the cooling towers.

Auxiliary Boilers

The proposed facility will either include a 55.34 MMBtu/hr auxiliary boiler or a 41 MMBtu/hr boiler depending on the type of turbine that is purchased. Due to the size of the boilers, it would be economically impractical to install any kind of control device.

The emissions from the auxiliary boiler are so low that potential emission reductions from controls are not cost-effective. As demonstrated in the BACT analysis for NO_x, the largest emission reduction is 0.52 tpy (considering a 98.6% reduction). At such a reduction, the capital cost of a control system would need to be quite inexpensive to be cost-effective, and is below the cost of available controls. Consequently, the application of control technologies are not cost-effective and low-NO_x burners are determined as BACT for NO_x.

Emissions of CO and VOC are also low. As a result, an add-on control device such as an oxidation catalyst would not be cost-effective. As with the combined-cycle units, no add-on control devices have been identified for the control of PM_{10} or SO_2 from the auxiliary boiler. Combustion controls and the use of natural gas are considered BACT for CO, VOC, PM_{10}, and SO_2 from the auxiliary boiler.

Fire Water Pump and Emergency Generator

If the Permittee installs SW501F turbines, the proposed facility will include two generator sets. Each generator set will be made up of one emergency generator and one fire water pump. If the Permittee installs GE7FA turbines, the proposed facility will include one generator set. This generator set will be made up of one emergency generator and two fire water pumps.

Each generator set will be limited to 500 hours of operation per year. This limitation on the hours of operation results in minimal emissions. As a result, BACT for the engines was determined to be good combustion control as provided by modern engine control systems.

AMBIENT IMPACT ANALYSES

PSD regulations under Title I of the Federal Clean Air Act (CAA) and Arizona Administrative Code (A.A.C.) R18-2-406(A)(5), and the impacts analysis requirements under those regulations are applicable to the La Paz Generating Facility for PM_{10}, NO_x, SO_2, and CO. The impacts analysis is designed to protect the National Ambient Air Quality Standards (NAAQS) and PSD increments.

The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere. For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the background concentrations and the estimated ambient impacts of Allegheny's proposed emissions. A PSD increment, on the other hand, is the maximum increase in ambient concentration that is allowed to occur above a baseline concentration for a pollutant. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment.

Modeling was performed to determine if the La Paz Generating Facility would meet the PSD Class I wilderness area and Class II wilderness area increments for nitrogen dioxide (NO_2), SO_2, and PM_{10}, and the NAAQS for NO_2, SO_2, PM_{10}, CO, and lead. All of the modeling that was conducted conformed with guidance issued by the Department, the EPA, and the Federal Land Managers

(FLM).

Modeled ambient concentrations showed compliance with the standards for all criteria air pollutants. When including emissions from all additional pollutant sources within 50 miles, all of the maximum predicted impacts were less than PSD increment levels and NAAQS. The following are the additional sources that were included: Sonas Soil Treating (Vicksburg), Phoenix Agro, Harquahala Generating Station, Chickasha Cotton Oil Co., Mesquite Power Plant, and Arlington Valley Power Plant. Maximum predicted concentrations for CO and SO_2 were less than the significant impact levels (SILs), and therefore full modeling analyses were not conducted for these pollutants. Maximum modeled concentrations for NO_2 and PM_{10} were greater than the SILs, so full modeling analyses were conducted for those pollutants. The highest 24-hour PM_{10} predicted concentration from the La Paz Generating Facility was 8.6 micrograms per cubic meter (Fg/m^3), while the highest annual NO_2 result was 4.6 Fg/m^3, both of which demonstrate compliance with the PSD increment and the NAAQS.

In order to ensure the safety and welfare of the surrounding community, the Department also compared the modeled impacts from the La Paz Generating Facility and the other surrounding emission sources with the Arizona Ambient Air Quality Guidelines (AAAQGs). The comparisons demonstrated that the maximum predicted concentrations of all pollutants are less than the short-term AAAQG values. The AAAQGs are considered to be very conservative guidelines because they use potential to emit (PTE) calculations, which are based on a worst case scenario, and the AAAQGs include a safety factor of 10 to account for sensitive populations. Therefore, the Department has determined that there will not be an adverse impact on the public and the environment.

The modeling assessment for impacts at PSD Class I wilderness areas also demonstrated that maximum impacts would be less than all PSD increment levels.

PUBLIC PARTICIPATION PROCESS

Comments and questions were received during the public comment period in both verbal and written formats. This summary presents the Department's responses to the issues raised during the public comment period. Note that many of the comments addressed below relate to matters that are not directly at issue in this permit proceeding.

Please note that "C" represents the question or comment, and "R" represents the Department's response.

C: **The values listed in Table 2 of the Technical Support Document do not coincide with the values listed in the draft permit. The start-up limits listed in the draft permit for NO_x represent the maximum lbs/hr rate averaged over the start-up period while the CO limits are the maximum lbs/hr rate averaged over each one hour period. The maximum allowable NO_x emission rate for the SW should be 100 lbs/hr and for the GE, it should be 116 lbs/hr. The CO values should be 1131 lbs/hr for the SW and 1764 for the GE. These are the values listed in the draft permit and Table 2 should reflect these values along with the proper notations regarding the averaging periods.**

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: **Emissions for each CTG for CO in Table 3a of the Technical Support Document should be 220.6 (14.25*7977/2000+163.8) based on maximum hourly values listed in Table 1. The value of 163.8 is the total annual CO emissions from startups. Thus the total CO should be 906.0 tons (220.6*4+21.8+1.8).**

The total PM_{10} emissions should be 581.2 (132.7*4+46.4+3.6+0.4).

R: The Department recognizes that there were typograghical errors for the CO emissions and will make the corresponding changes. With respect to the PM_{10} emissions, the Department reviewed the calculations and determined that the value contained in the TSD is correct. Therefore, this portion of the condition will remain unchanged.

C: **Emissions for each CTG for CO in Table 3b of the Technical Support Document should be 265.4 (15.95*7977/2000+201.8) based on maximum hourly values listed in Table 1. The value of 201.8 is the total annual CO emissions from startups. Thus the total CO should be 1078.7 tons (265.4*4+21.8+1.8).**

The total for VOC emissions is incorrect and should be 243.9 (60.5*4+1.8+0.1).

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: **In the PM_{10} column for each Combined Cycle System Exhaust in Table 4 of the Technical Support Document, the value of 0.0148 lb/MMBtu should be listed for the SW501F not for the GE7FA, and vice versa for the value of 0.0188 lb/MMBtu.**

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: **The PTE values should be revised in Table 5a of the Technical Support Document to reflect the changes discussed above. CO should be 906.0 tpy and PM_{10} should be 581.2 tpy.**

R: The Department recognizes that there were typograghical errors for the CO emissions and will make the corresponding changes. With respect to the PM_{10} emissions, the Department reviewed the calculations and determined that the value contained in the TSD is correct. Therefore, this condition will remain unchanged.

C: **The PTE values should be revised in Table 5b of the Technical Support Document to reflect the changes discussed above. CO should be 1078.7 tpy and VOC should be 243.9 tpy.**

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: **The opacity limit for the turbines in the "Emission Limits" row and "Proposed Permit Condition" column in Table 6 of the Technical Support Document should be 20%, not 10%, based on requirements of 40 CFR 60.43a(b).**

R: In order to ensure continuous compliance with the BACT limit for PM_{10}, the Department has established this opacity limit as a surrogate BACT limit. Therefore, a limit of 10% is the appropriate and necessary limit for the Combustion Turbines.

C: **For NO_x, in Table 14a of the Technical Support Document the Impact (column 5) should be 19.4 and %PSD (column 7) should be 9.6.**

R: The Department disagrees with this comment as the numbers in the table represent a more conservative analysis of the potential impacts from this facility. There was, however, a typographical error in Table 14a, the Predicted Max value for NO_x will be changed from 2.4 to 2.6.

C: **For SO_2 annual in Table 14b of the Technical Support Document, the Pred Max (column 3) should be 0.9, the Impact (column 5) should be 4.9, the %PSD (column 7) should be 4.50 and the %NAAQS (column 9) should be 6.13.**

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: **Table 15b of the Technical Support Document has the same exact numbers as Table 15a, which is for the GE turbines. The values for the SW turbines that should go in this table can be found in the original Application, Table G.4.**

R: The Department disagrees with this comment. The values that are in Table 15b are not identical to Table 15a and reflect the impacts of the Siemens Westinghouse turbines.

C: **Condition II.A.2.a.**

CO emissions rate should reflect TSD value of 1078.7 tons per year.

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: **Condition II.A.2.b.**

CO emissions rate should reflect TSD value of 906.0 tons per year.

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: **Condition II.A.3.a.**

VOC emissions rate should reflect TSD value of 243.9 tons per year.

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: Condition II.A.3.b.

VOC emissions rate should reflect TSD value of 193.4 tons per year.

R: The Department recognizes that there were typograghical errors and will make the corresponding changes.

C: Condition II.A.4.b.

PM_{10} emissions rate should reflect TSD value of 581.2 tons per year.

R: The Department reviewed the calculations and determined that the values contained in the permit is correct. Therefore, this condition will remain unchanged.

C: Condition III.C.2.b.

The opacity limit in this section for the CTG/HRSGs should be 20%, not 10%, based on the requirements of 40 CFR.42.a(b). The following statement should also be added at the end of the condition: *"except for one 6-minute period per hour of not more than 27% opacity."* There is no requirement basis for a 10% opacity limitation. Furthermore, a 10% opacity limitation is not required to meet the PM_{10} limits specified in Condition II.C.2.a.

R: In order to ensure continuous compliance with the BACT limit for PM10, the Department has established this opacity limit as a surrogate BACT limit. Therefore , a limit of 10% is the appropriate and necessary limit for the Combustion Turbines. The citation has been changed to A.A.C. R18-2-406.A.4 to reflect this.

C: Condition III.H.10.a(3)(c)

The requirements to include in the semi-annual system performance reports the daily gas stream flow and temperature data (flow going into the duct-burning system, and flow before and after SCR system) should be deleted. The facility is required to measure the daily flow rate and gas stream flow rates will be calculated using the fuel flow data and F-factors.

R: The Department has decided that in order to adequately determine compliance with the nitrogen oxide limits and appropriate operation of the SCR, that the daily flow rate and gas stream flow rate reporting requirements will be included in the permit.

C: Condition IV.B.1.b.

The opacity limit in this section for the cooling towers should be 40%, not 5%, based

on the requirements of A.A.C. R18-2-730. There is no regulatory basis for a 5% opacity limitation. Furthermore, a 5% opacity limitation is not required to meet the PM_{10} limitation specified in Condition IV.B.1.a.

R: In order to ensure continuous compliance with the BACT limit for PM10, the Department has established this opacity limit as a surrogate BACT limit. Therefore , a limit of 5% is the appropriate and necessary limit for the cooling towers. The citation has been changed to A.A.C. R18-2-406.A.4 to reflect this.

C: Condition V.B.6

The opacity requirement of 10% for the auxiliary boiler should be deleted. The auxiliary boiler under both turbine configurations is not subject to an opacity limit under 40 CFR subpart Dc because it will burn only natural gas. Since the auxiliary boiler is subject to NSPS, it is not subject to non-NSPS requirements of Title 18, Chapter 2 of the A.A.C. Furthermore, an opacity limit is not required to meet the PM_{10} limitations specified in Section V.B.2.

R: In order to ensure continuous compliance with the BACT limit for PM10, the Department has established this opacity limit as a surrogate BACT limit. Therefore , a limit of 10% is the appropriate and necessary limit for the auxiliary boiler. The citation has been changed to A.A.C. R18-2-406.A.4 to reflect this.

C: Condition V.H.1.d.

This requirement should be deleted as the auxiliary boiler will only burn natural gas and therefore, is not subject to 40 CFR 60.42c(a) or (b)(1) which pertain to boilers burning coal.

R: The Department agrees with the comment and will make the corresponding changes.

C: There were concerns that citizens were not notified of the construction of the power plant.

R: In accordance with Arizona Revised Statute (ARS) §49-426.D, a Public Notice was issued in the Parker Pioneer on January 29, 2003 & February 5, 2003, and the Quartzsite Times on January 29, 2003 & February 5, 2003. A Public Meeting and a Public Hearing was held on Tuesday, February 18, 2003, and Tuesday, March 4, 2003, respectively. Both the meeting and hearing were held at 7:00 pm at Salome Elementary located at 38128 Saguaro in Salome, Arizona. The Department also requires the source to post a notice containing the following information at the site where the source is to be located:

- Identification of the affected facility;
- Name and address of the Permittee or applicant;
- Name and address of the permitting authority processing the permit action;
- The activity or activities involved in the permit action;
- The emissions change involved in any permit revisions;

- The air contaminants to be emitted;
- A statement that any person may submit written comments or a written request for a public hearing, or both, on the proposed permit action, along with the deadline for such requests or comments;
- The name, address and telephone number of a person from the Department from whom additional information may be obtained; and
- Locations where copies of the permit application, the proposed permit, and all other materials available to the Director that are relevant to the permit decision may be reviewed, including the closest Department office, and the times at which they shall be available for public inspection.

C: There were concerns about where the power was going.

R: The AQD does not have jurisdiction over this issue, and therefore this comment could not be considered as a part of this permitting action.

C: There were questions regarding what could be done to stop the construction of the power plant.

R: In accordance with Arizona Revised Statute (ARS) §49-427.A, the Department is required to issue a permit or permit revision to the applicant unless it can be proven that the facility has not been designed, controlled or equipped with air pollution equipment that will ensure that the facility is not capable of causing air pollution that violates air quality standards. The public has the opportunity to comment on the permit during the public notice period. The Department will consider all comments received before making a decision to issue or deny the air quality permit.

C: There was confusion with regards to whether or not this power plant is the same plant that is being built in the area.

R: The La Paz Generating Facility will be a natural gas fired combined cycle merchant power plant with either a rating of 1,080 Megawatts (MW) or 1,040 MW depending on the type of turbine that Allegheny decides to install. The power plant currently under construction is the Harquahala Generating Facility which is a natural gas fired combined cycle power plant that is rated at 1,060 MW and was permitted by Maricopa County.

C: There were concerns about the ammonia emissions from the plant.

The permit has a limit of 7.5 parts per million dry volume (ppmvd) at 15% oxygen for ammonia emitted into the atmosphere. In order to ensure the safety and welfare of the surrounding community is protected, the Department compared the modeled impacts from La Paz Generating Facility and the other surrounding emission sources with the Arizona Ambient Air Quality Guidelines (AAAQGs). The comparisons demonstrated that the maximum predicted concentration of ammonia is less than the short-term AAAQG values. The 24 hour AAAQG for ammonia is 140 Fg/m^3, and the maximum model-predicted concentration is 7.6 Fg/m^3 for the GE7FA turbine and 6.3 Fg/m^3 for the SW501F turbine.

C: **There were concerns with regards to how the power plant will impact the water table and the water wells in the surrounding area.**

R: The AQD does not have jurisdiction over this issue, and therefore this comment could not be considered as a part of this permitting action.

ABBREVIATIONS

AAAQG	Arizona Ambient Air Quality Guideline
A.A.C.	Arizona Administrative Code
ADEQ	Arizona Department of Environmental Quality
ACC	Air Cooled Condenser
AQD	Air Quality Division
ARS	Arizona Revised Statutes
BACT	Best Available Control Technology
BTU	British Thermal Unit
C	Comment
CAA	Clean Air Act
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
CTI	Cooling Technology Institute
EF	Degrees Fahrenheit
EPA	United States Environmental Protection Agency
FLM	Federal Land Manager
ft	Feet
GE	General Electric
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
hr	hour
HRSG	Heat Recovery Steam Generator
ISO	International Standards Organization
lb/hr	Pound per hour
$\mu g/m^3$	Microgram per Cubic Meter
MMBtu	Million British Thermal Units
MW	Megawatt
NAAQS	National Ambient Air Quality Standard
NO_x	Nitrogen Oxide
NO_2	Nitrogen Dioxide
PM	Particulate Matter
PM_{10}	Particulate Matter Nominally less than 10 Micrometers
ppm	Parts Per Million
ppmvd	Parts Per Million by Volume-Dry
PSD	Prevention of Significant Deterioration
R	Response
PTE	Potential-to-Emit
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SIL	Significant Impact Level
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator

SW	Siemens Westinghouse
TDS	Total Dissolved Solids
tpy	Tons Per Year
VOC	Volatile Organic Compound
yr	year